COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

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NSTAR Electric Standby Rate Tariffs	)	D.T.E. 03-121

COMMENTS
Of

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I've had a chance to review the testimony of Mr. LaMontagne and I agree with him on the goals for this type of tariff. However, I disagree with the proposed rate structure for standby service, as described. For example, starting with page 10, line 18, Mr. LaMontagne lists the Department's policy goals:

> Standby service tariffs should ensure that customers pay an appropriate share of distribution system costs.
>
> Standby service tariffs should provide an appropriate price signal to customers seeking to install DG (i.e., the price should reflect the full cost of providing the standby service to the DE customer).
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> Standby service tariffs should reflect the actual cost of providing standby service to DG customers in order to avoid shifting these costs to other customers.
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> (Order Opening Investigation into Distributed Generation,
> D.T.E. 02-39, at 4 (June 13, 2002)).

He then elaborates and extends further on those goals in the following pages, by listing characteristics of appropriate standby rates and the observations on p11 @ 14:

> "A next generation" of standby rates is appropriate that will: (1) facilitate the development of cost-effective DG; (2) avoid inappropriate cross-subsidization of costs among customers; and (3) send the appropriate economic price

> signals to customers considering DG options not previously available in the market."

Further, he lists traditional ratemaking goals in line 23 (p11),

> "Fairness, economic efficiency, simplicity, rate stability (rate continuity), and earning stability…."

Most of these rate and policy goals are based on the concept of "cost causation" and are appropriate when applied to standby rates. However, the proposed rate structure fails at all of them, except perhaps in the cases of simplicity and earning stability. In the short term, the delay in the implementation of DG, which this rate structure would cause, would provide for some earning stability. But the technological development of DG will continue nonetheless. Should the technology evolve that allows customers to economically operate independent of the grid, the results would be very disruptive to income stability for the utility. In the longer term, it would be better to provide proper pricing of standby services that would allow for steady growth in DG.

The problem with the proposed rate structure is that it has no basis in cost causation. The company asserts that its costs and obligations to customers who generate some of their own power are substantially different from customers who do not. The company argues that it must maintain reserve capacity in the distribution system to serve load when a customer's generator does not operate. It further argues that it needs to do this for each individual customer on a kW to kW basis. That is, it must reserve a kW of capacity within its system for each kW of generator capacity that the customer has. In effect, these assertions assume that all generators will fail simultaneously.

The company further argues that since fixed costs are a major component of distribution costs, they should be recovered through fixed payments, i.e., demand charges. Since they view the standby charge as a reservation charge, they further argue that it should be in the form of a contract demand charge, to be paid whether or not the capacity is used. In effect, the company says that customers with generation are so different from conventional customers that the normal rate structures are inadequate to properly recover costs. Generally these assertions are baseless. While its true that the residual loads of customers with generation may vary widely, the range of variation is no more than it would be among conventional customers.

For example, consider two customers that present exactly the same load shapes to the distribution system. The first has a 100 kW generator running full time; the second does not, but has a 100 kW compressor that does not normally run. One customer is the mirror image of other. If the generator were shut down for one hour during the month, the effect on the distribution company would be exactly the same as having the compressor operating for that same hour. The cost to the distribution company and its obligation would be exactly the same. To the extent that the normal rate structure recovers the cost of the conventional customer, then it would also recover the cost of the generating customer. The utility has the same obligation to have 100 kW available in either case.

Likewise if the generator is off for half the time and the compressor is on for half the time, then the customers again have the exactly same effect on the distribution company. Again, if the conventional rate structure adequately represents the cost of service and obligations for the non-generating customer, then it also adequately represents the cost of service for the generating customer.

If a reservation charge is required for the generator, it should also be required for the compressor on a kW for kW basis. By extension, every device that can be put onto the distribution system should have a reservation charge associated with it, whether or not it's used. In the extreme, a toaster, with a 1 ¼ kW load should be paying about $30 / month in reservation fees in the summer. The effect of a kW of load that might sometime be on the system is exactly the same whether or not there's a generator involved.

It's possible that the conventional rate structure does not adequately cover the cost of the individual generating customer, but under those conditions it would not cover the cost of the non-generating customer either. But that's not a problem attributable to the generator - it's a problem of the rate structure itself. Conventional two-part monthly demand and commodity rate structures do not do a good job of allocating cost for a non-standard customer, whether or not they generate.

The basic questions are how to charge a customer for capital investments made, and how to indicate to customers in the price that their use of the system may signal the need for additional investment. The problem is how to allocate these fixed costs among the various users of the investment. Since the customers do not necessarily draw their power at the same time, the resource is shared. The company does not build the system to accommodate the total connected load. Instead, it is designed to match the actual coincident peak load, with a substantial reserve to cover contingency and growth.

In a system where capacity can be shared, the better method for billing would be on a unit of usage basis. That is, those that use the system more, pay more, and those that use the system less, pay less. In a system with excess capacity, it doesn't really matter how much they use at any given time. So in the case of a distribution system, a payment by kWh would provide the proper signal. At times when the system approaches higher levels of loading and we begin to see congestion, the price per kWh has to go higher to reflect the probability of need for system reinforcement and additional investment. Traditional ratemaking has examined the load shapes of different classes of customers to establish their contribution to the probability of peak. Based on the findings, the costs of the system have been allocated to each of the classes on the basis of usage (per kWh) or a combination of demand and usage (per kW plus kWh). In the case of smaller customers the fixed payment per kWh has been considered adequate to recover costs; in the case of larger customers, somewhat better cost allocation has be attained by adding a demand charge. The problem is that the demand is a poor proxy for contribution to peak, since the customer's demand can be set when capacity is either short or not. The customer sees the same charge whether the power is used during heavily loaded periods or lightly loaded periods. Time of day and seasonal adjustments improve the pricing further, but still do not reflect the impact of an individual customer on the system. These rate structures have been largely constrained by our ability to meter the customer's usage. Today, we have the possibility of monitoring the customer's usage and pricing the power on a variable basis that actually reflects the cost at any given time. Further, that pricing information can be communicated to the customer so that they can respond, if they choose to, through load deferrals, or generation or, for that matter, through increased consumption when appropriate.

Concern has been expressed that the installation of generation in the distribution system will result in a loss of income for the company that would be passed on to other customers. While this is certainly possible, several factors would limit the exposure. Growth in generation at rates less the company's rate of deprecation would not raise prices in the short term and over time, the expense of new construction could be deferred. In addition, the added generation would keep pressure on the price of power itself reducing any distribution increase.

We must remember that the utility has the responsibility to plan for changing technologies.

CONCLUSION

The standby rate proposed by NSTAR does not meet the various objectives that must be met.

I believe the existing rates should be maintained in the near term and the process of developing a real time variable adder that reflects the state of the distribution system should be begun.